This Page Blank (uspto)

(12) UK Patent Application (19) GB (11) 2 356 207 (13) A

(43) Date of A Publication 16.05.2001

(21) Application No 9926545.6

(22) Date of Filing 09.11.1999

(71) Applicant(s)
Stephen John McLoughlin
36 Wychwood Close, Craigwei, BOGNOR REGIS, West Sussex, PO21 4DW, United Kingdom

(72) Inventor(s)
Stephen John McLoughlin

(74) Agent and/or Address for Service
Marks & Clerk
57-60 Lincoln's Inn Fields, LONDON, WC2A 3LS, United Kingdom

(51) INT CL[7]
E21B 47/12 47/16

(52) UK CL (Edition S)
E1F FHK

(56) Documents Cited
GB 2352743 A WO 96/31679 A US 4763258 A
US 3908453 A

(58) Field of Search
UK CL (Edition S) E1F FCB FCU FHK
INT CL[7] E21B 7/06 7/08 47/12 47/16 47/18
EPODOC, WPI, JAPIO

(54) Abstract Title

Apparatus and method for transmitting information to, and communicating with, a downhole device.

(57) An apparatus(2) for use in drilling comprising a downhole member capable of being attached to a tubular(25), means for rotating the tubular(25), control means(27) for controlling the rotation of the tubular(25) in order to transmit information along the tubular(25) and means for monitoring(29) and decoding the information transmitted. The information can be transmitted via any combination of speed, duration of rotation, time between successive rotations and direction of rotation of the tubular(25) or by no rotation at all. This allows binary or information of exact magnitudes to be transmitted. Means for monitoring(29) the rotation include emitter devices eg. magnets or mechanical switches which emits a signal or influences its surroundings such that the rotation activates sensing means. The sensor detects changes in the field or signal produced by the emitter caused by rotation of the tubular(25). The output from the sensor will activate means for controlling the drill or other device to act in a way as required by the information transmitted by the tubular(25). The apparatus can be used in conjunction with any downhole device eg. steering tools.

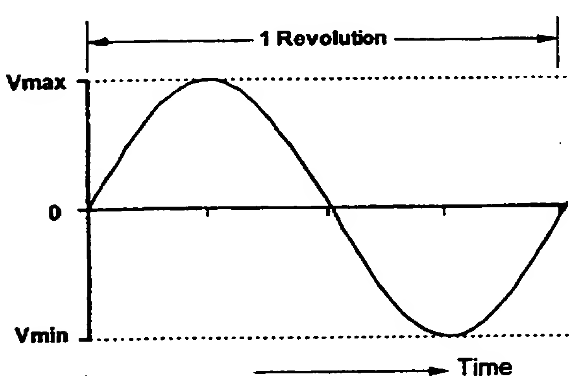


FIG 1A

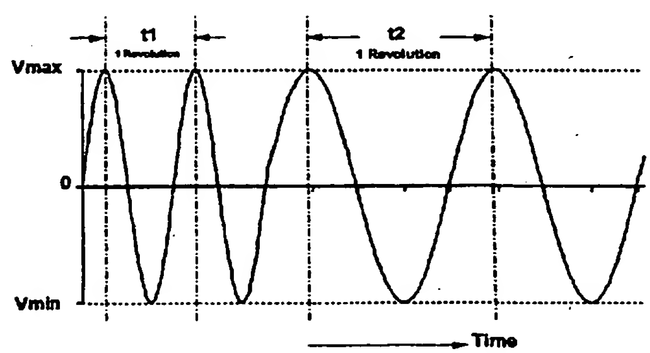
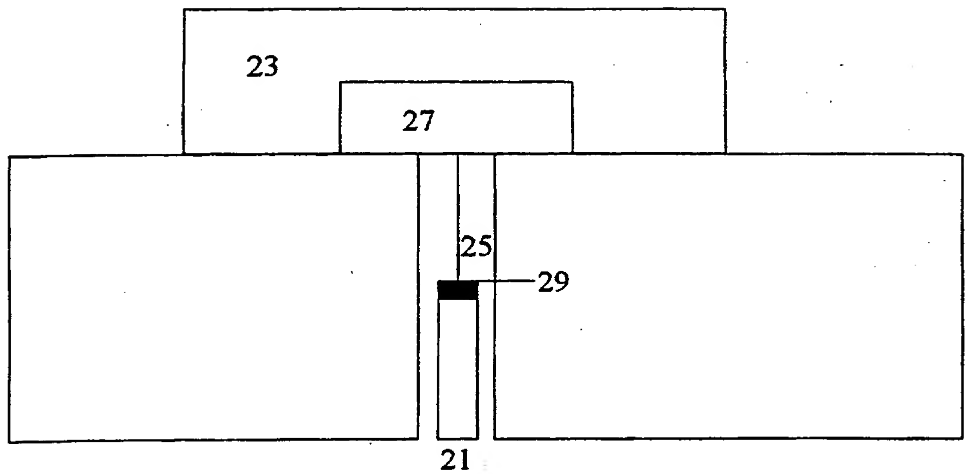


FIG 1B

GB 2 356 207 A

Figure A



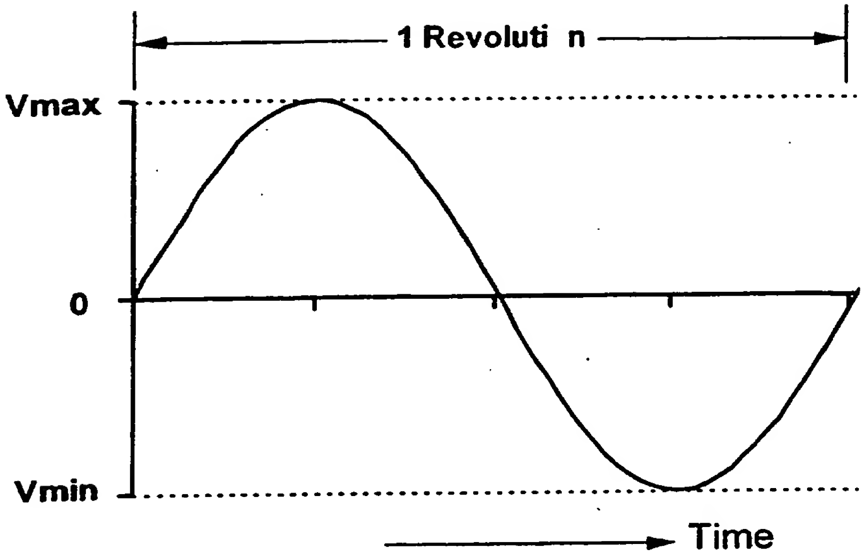

1 Revoluti n
Vmax
0
Vmin
Time

FIG 1A

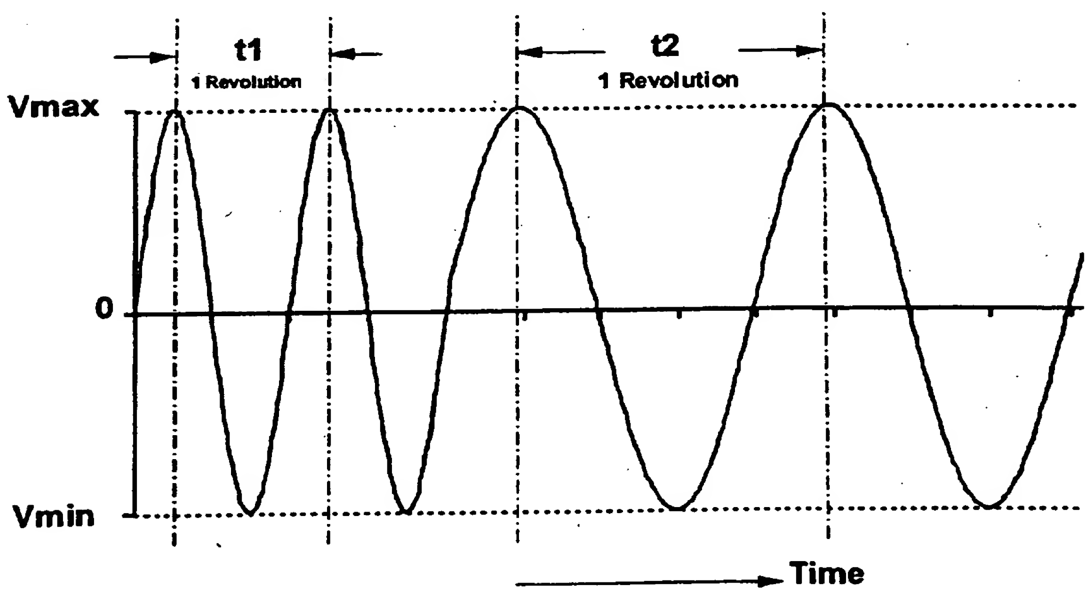

t1
1 Revolution
t2
1 Revolution
Vmax
0
Vmin
Time

FIG 1B

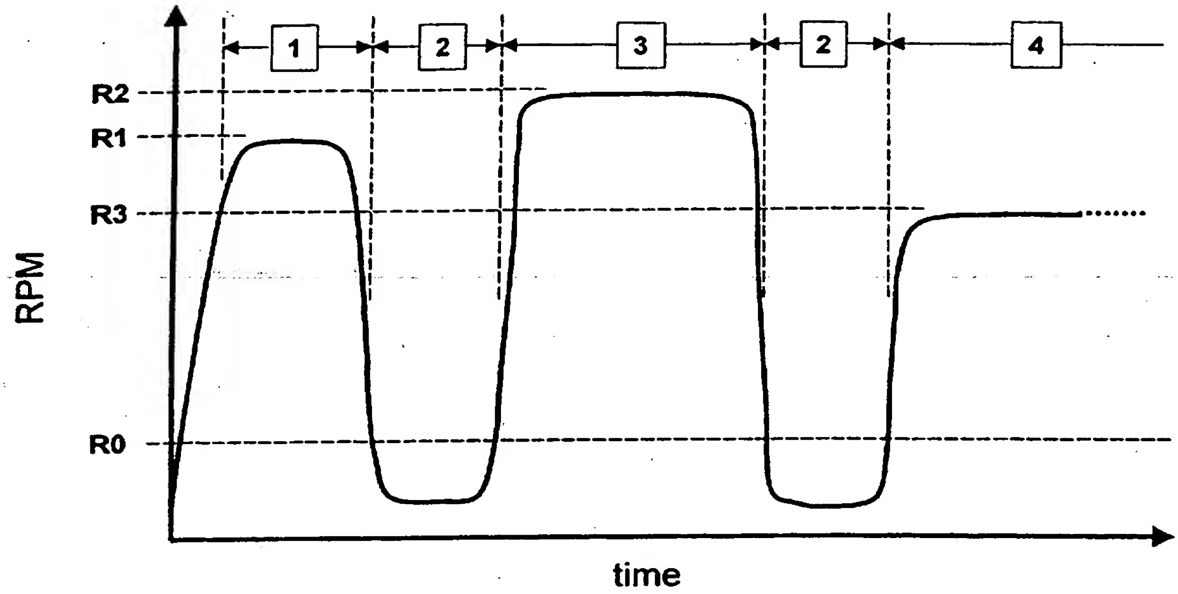


FIG 2A

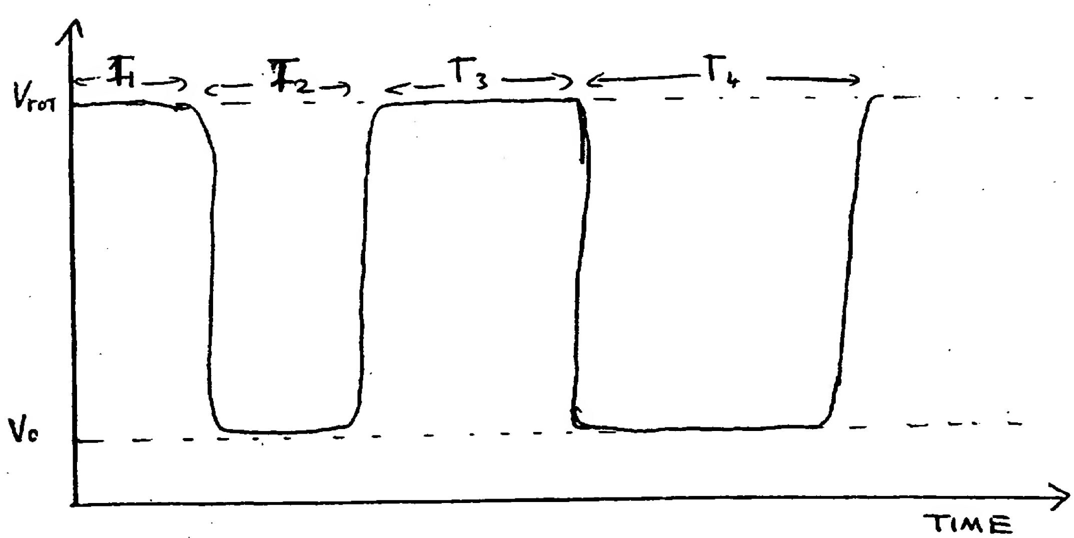


FIG 2B

4/6

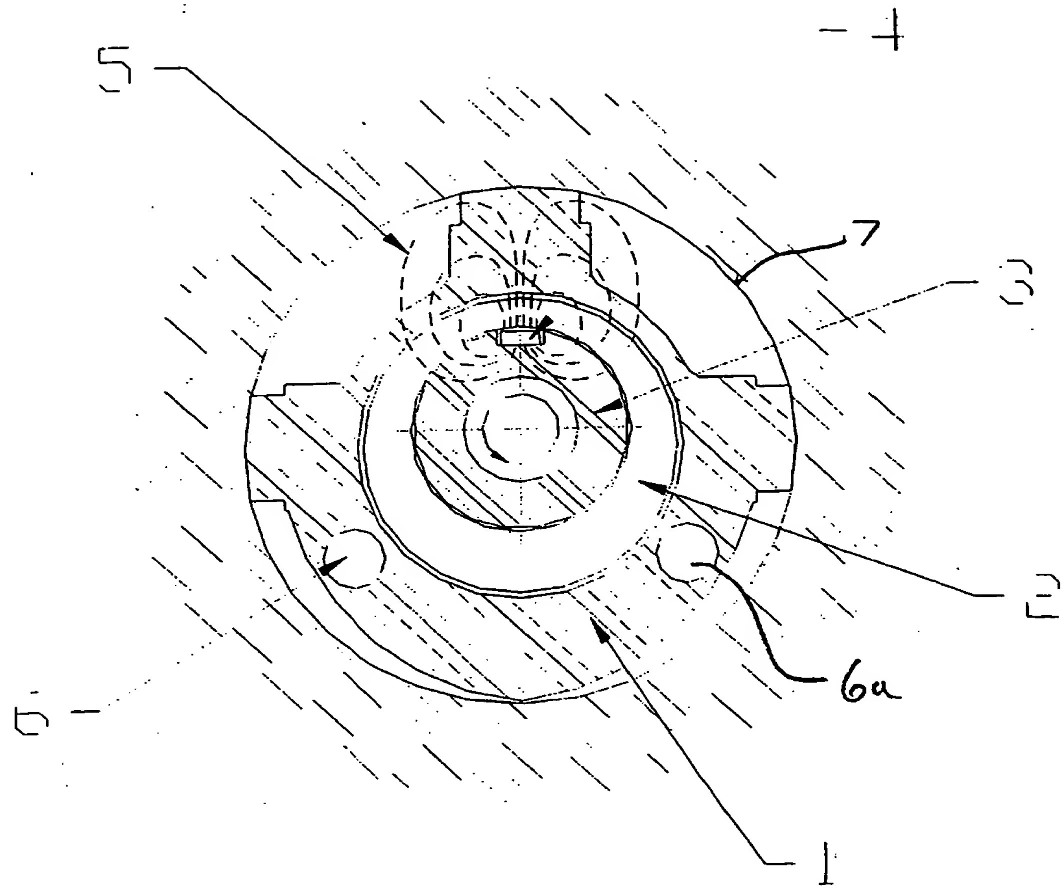


FIG. 3A

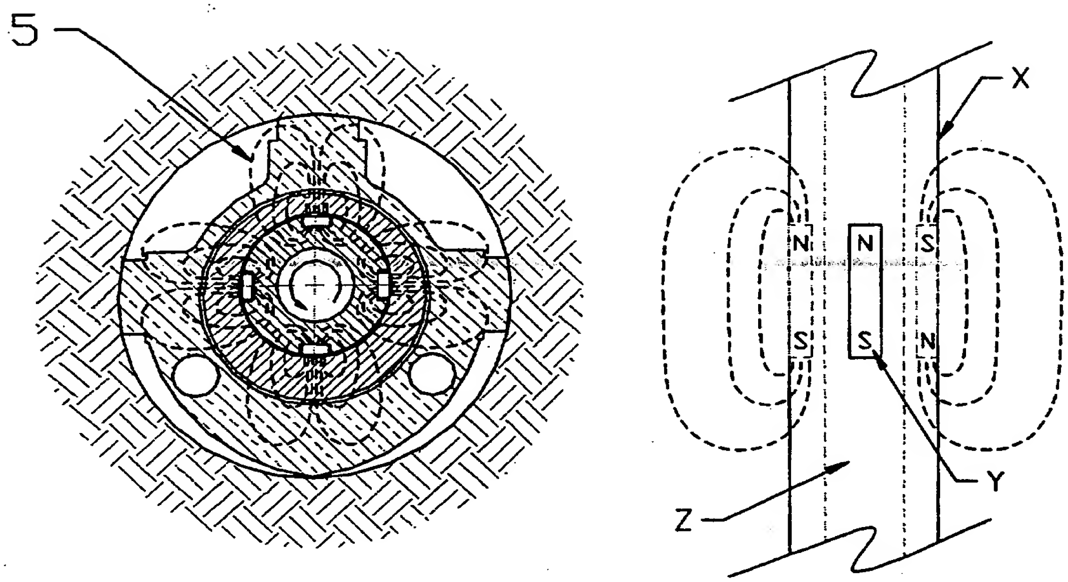
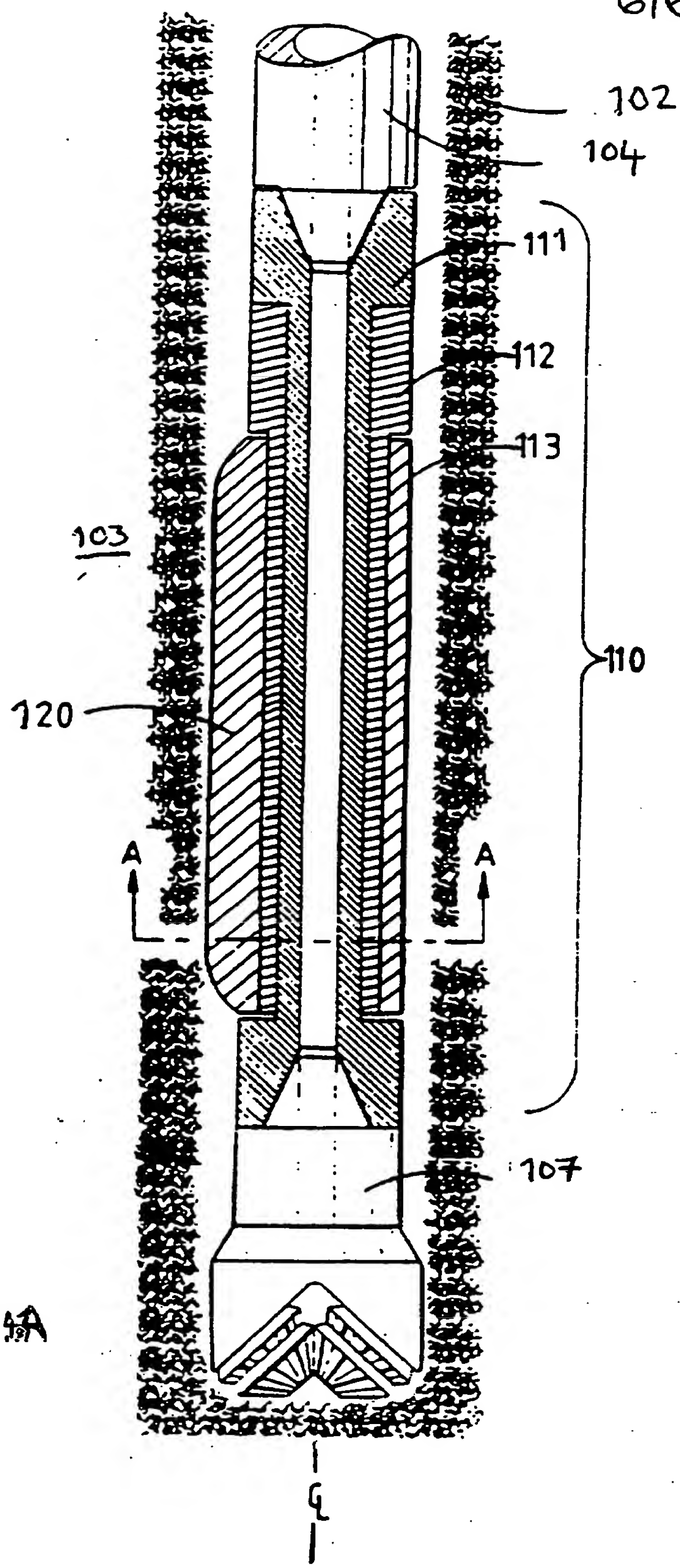
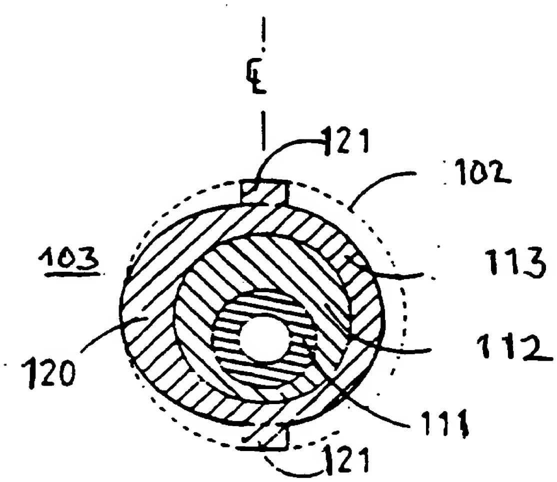


FIG.3B



102
104
111
112
113
110
103
120
A
A
107
℄

FIG.4A



℄
121
102
103
113
112
120
111
121

FIG.4B

Apparatus and Method for Transmitting Information to and Communicating with a Downhole Device

The present invention is concerned with the field of downhole tools. More specifically, the present invention is concerned with an apparatus and method for transmitting information to a downhole tool.

A drilling tool or member is a device suitable for drilling a well bore or the like. As the drilling tool drills further into the ground, communicating with the tool becomes more and more difficult. Other downhole tools, variously referred to as "production tools", fulfilling different functions from drilling tools yet having similar data requirements to drilling tools are considered equally within the scope of this apparatus and method.

The recognised term in the art for the method of transmitting information from the drilling tool to the surface is 'telemetry'. Telemetry can be achieved by many means, for example, 'hardwire', where the signal is passed along a conducting medium via electrical means and to which the drilling tool is attached.

The above telemetry method requires the provision of a separate communication route for the electrical signal from the surface. This provides drawbacks in terms of both cost and potential reliability as the signal must reach the tool when the tool is many miles below the surface.

A telemetry medium for communicating with the tool should ideally be one of the parameters which is readily available in either drilling or production scenarios. A drilling parameter is a parameter which must be supplied to the drilling tool in the vast majority of drilling scenarios.

Drilling parameters such as the 'weight-on-bit', pump cycling and drill string rotation have been previously been considered. However, generally, these have been used just to toggle a switch between two states, and represent, at worst a binary switching device and, at best, a means of stepping through multiple options.

The drill string rotation is a drilling parameter which is common to almost all rotary drilling operations. This is typically measured in revolutions per minute (RPM). Variations in the rotation of the drill string can be used, be that in terms of the actual rotational velocity, the time when the drilling string is continuously rotating at a continuous speed or a measured time when the drill string is not rotating can be used to transmit a sophisticated command sequence, wherein the rotary commend parameter has magnitude. This is as opposed to the conventional toggle signal transmitted down the drill string to the drilling tool. Thus, this new apparatus and method addresses all the problems posed by the known prior art.

Although the term "drill string" has been used, it will be appreciated that the "drill string" could be any tubular which is connected to a downhole tool. For example, rotation of a production string could also be used if the downhole tool is a production tool. A tubular can be any pipe or any medium which generally connects the downhole tool (when in position in the well bore) with a surface control station, providing that rotation of the tubular at the surface causes rotation of the tubular at the downhole tool.

Therefore, in a first aspect, the present invention provides an apparatus for use in drilling or producing from a well bore, the apparatus comprising a downhole member capable of being attached to a tubular, means for rotating a tubular, control means for controlling the rotation of said tubular in order to transmit information along said tubular and means for monitoring the rotation of said tubular and for decoding said information transmitted along said tubular such that a magnitude of a parameter can be determined from the rotation of said tubular.

As previously described, the tubular may be a drill string, production string or the like. The downhole member may be a drilling tool, production tool or the like.

In a second aspect, the present invention provides a method for transmitting information along a tubular to a downhole member located within a well bore, the method comprising the steps of:

rotatably driving said tubular, wherein the rotation of said tubular is controlled in accordance with information which is to be transmitted along said tubular;

monitoring the rotation of said tubular; and

analysing the monitored rotation of said tubular such that a magnitude of a parameter can be determined from the rotation of said tubular.

The variation in the tubular rotation may be provided by varying the rotational velocity of the tubular, measuring the time for continuous rotation of the tubular, measuring the time between successive rotations of the tubular (i.e. the time when the tubular is not rotating), or any of the above parameters in either separately or in combination etc.

This ability to vary the rotational speed of the tubular allows a magnitude to be communicated to the downhole member as opposed to just a binary signal. Therefore a signal, such as a magnitude of the change in a drilling angle can be communicated to the tool by using just the tubular rotation.

The rotation of the tubular may be monitored by the use of an emitter device which emits a signal or influences its environment such that the rotation of the drill string is used to activate a sensor means.

The emitter device which emits a signal or influences its environment may comprise a magnet. Alternatively, or in addition to the magnet, the device may also comprise a device which emits a sonic or a radioactive signal.

The emitter device may be located on the tubular or on a non-rotating part of the apparatus.

The emitter device may comprise a mechanical switch which is activated by the rotation of the tubular, such that each revolution is equal to an analogue or digital data point.

The rotation of the tubular may be monitored using a sensor. The sensor may sense or change a field or signal emitted by the emitter. For example, if the emitter is a magnet then the sensor may be a Hall effect device or a magnetometer. Alternatively, the sensor may by used to sense changes in an inherently present parameter due to the rotation of the tubular. For example, the sensor may comprise an accelerometer which receives direct alternating gravitational data inputs as a direct result of the rotation of the tubular.

Preferably, the sensor means comprises a timing device such that sensor outputs derived from the rotation of the tubular may be measured over time.

A plurality of emitter and/or sensors may be provided. If a plurality of emitter devices and/ or sensor means are provided then each of the devices and/or sensor means may be actuated in an independent or sequential manner. The plurality of emitters may be located radially or axially on the rotating drill string. If the emitters are a plurality of magnets then the magnets may be aligned with alternating polarities.

The output from the sensor means may be analogue or digital. The output from the sensor means will generally be provided to a drive means or a logic means in order to control the drilling member or other device in accordance with the information transmitted down the drill string.

The apparatus and method according to the first and second aspects of the invention (respectively) may be used with any downhole device where it is necessary to transmit a control parameter to the device, for example, to control the drilling direction.

However, they are especially suited for use with a wellbore directional steering tool as described in WO-A-96/31679. The latter device is an apparatus for selectively controlling from the surface, the drilling direction of wellbore. It comprises a hollow rotatable mandrel, an inner sleeve, an outer housing, a plurality of stabilizer shoes and a drive means. The hollow rotatable mandrel has a concentric longitudinal bore. The inner sleeve is rotatably coupled about the mandrel and has an eccentric longitudinal bore of sufficient diameter to allow free relative motion between the mandrel and the inner sleeve. The outer housing is rotatably coupled around the inner eccentric sleeve and has an eccentric longitudinal bore forming a weighted side. The outer housing also has sufficient diameter to allow free relative motion between the inner sleeve. Two stabilizer shoes are longitudinally attached to or formed integrally with the outer surface of the outer housing. Finally, the drive means is arranged for selectively rotating the inner eccentric sleeve with respect to the outer housing.

An embodiment of the directional tool is shown in Figures 4A and 4B. It is shown in a configuration whereby it is attached to an adapter sub. 104, which can be attached to the drill string (not shown). The adapter sub is attached to the inner rotatable mandrel 111 and may not be necessary if the drill string pipe threads match the device threads. The mandrel is free to rotate within the inner eccentric sleeve 112. The mandrel 111 is capable of sustained rotation within the inner sleeve 112. The inner eccentric sleeve 112 may be turned freely within an arc, by a drive means (not shown), inside the outer eccentric housing or mandrel 113. The bearing surfaces between the inner and outer mandrels are not critical as they are not in constant mutual rotation, but they must be capable of remaining clean and in relatively low torque with respect to each other in the drilling environment.

The inner rotating mandrel 111, is attached directly to a drill bit 107. However, the threads may differ between the two elements and an adapter sub may be required for matching purposes.

Figure B shows the relative eccentricity of the inner, 112 and outer, 113 eccentric sleeves (outer housing). The outer housing consists of a bore passing longitudinally through the outer sleeve which accepts the inner sleeve. The outer housing is eccentric on its outside, shown as the "pregnant portion", 120.

The pregnant portion or weighted side, 120 of the outer housing forms the heavy side of the outer housing and is manufactured as a part of the outer sleeve. The pregnant housing contains the drive means for controllably turning the inner eccentric sleeve within the outer housing. Additionally, the pregnant housing may contain logic circuits, power supplies, hydraulic devices, and the like which are (or may be) associated with the 'on demand' turning of the inner sleeve.

There are two stabilizer shoes, 121, on either side of the outer housing located at right angles to the pregnant housing and on the centre line drawn through the center of rotation on the inner sleeve. These two shoes serve to counter any reactionary rotation on the part of the outer housing caused by bearing friction between the rotating mandrel 111 and the inner eccentric sleeve 112. The stabilizer shoes are normally removable and are sized to meet the wellbore diameter. The same techniques used to size a standard stabilizer can be applied in choosing the size of the stabilizer shoes. Alternatively, the shoes 121 can be formed integrally with the outer housing 113. The pregnant or weighted portion of the outer housing 113, will tend to seek the low-side of the hole and the operation of the apparatus depends on the pregnant housing being at the low-side of the hole.

The manner of functioning of the apparatus and method of the present invention to control a drilling device such as a directional drilling device as shown in Figures A and B will be described in more detail hereinbelow.

The present invention will now be described with reference to the following non-limiting preferred embodiments in which:

Figure A shows a schematic of an embodiment of the present invention;

Figure 1A shows a single cycle of a typical accelerometer output;

Figure 1B shows a plot of an accelerometer output used to measure a rotating drill string with a variable rotation speed;

Figure 2A shows a plot of rotation speed against time;

Figure 2B shows a plot of rotation speed against time, where the drillstring is switched between rotating at a fixed speed and zero rotation;

Figure 3A shows a cross section of a drilling tool in accordance with an embodiment of the present invention;

Figure 3B shows a cross section of a drilling tool in accordance with another embodiment of the present invention.

Figures 4A and B show a prior art drilling tool.

Figure A shows a schematic of an embodiment of the present invention, the drilling tool 21 is connected to the surface station 23 via drill string 25. To effect rotational drilling, the drill string 25 is rotated.

Surface station 23 is provided with rotation control means 27 which controls the rotation of the drill string. The drilling tool 21 has monitoring means 29 which monitors the rotation of the drill string 25.

Figure 1A shows the output of an accelerometer as the drill string rotates. In a single rotation of the drill string, the accelerometer output changes from a zero point to V_{max}, returning to zero, and passing though zero to point V_{min} and then back to zero. The output of the accelerometer is generally sinusoidal with the magnitude of the maxim and the minima being V_{max} and V_{min} respectively. The amplitude and form of the wave is dependent on the attributes of the particular sensor being used and also the time it takes to complete a single 360° revolution.

In Figure 1A, the accelerometer is attached to the drill string. The starting point for the single rotation is taken from where a test mass in the accelerometer is in a neutral position.

Figure 1B shows an accelerometer output similar to figure 1A. Except, here, a number of rotation cycles of the drill string are shown and also, the rotational speed of the drill string is varied over time. The rotational speed of the drill string is generally measured in rotations per minute or RPM.

The output of the accelerometer in figure 1B shows three full rotation cycles of the drill string. The dotted vertical lines on the figure indicate the start and end of each cycle. Here, each cycle starts when the accelerometer output is at maximum V_{max}. However, it will be appreciated that any point of the cycle could be chosen as the start point.

The first rotation cycle has a period of t_1. Once this cycle is completed, the speed of rotation of the drill string is reduced over the second cycle until a third cycle with a period of rotation t_2 is achieved. Period t_2 is longer than period t_1, therefore, the speed of rotation in the first cycle is greater than that of the third cycle. Thus, a change in the rotation speed of the drill string can be detected at the drilling member or drilling tool. Hence, the rotation frequency of the drill string can be used to instruct the drilling member, downhole device or tool.

Figure 2A shows a plot of the rotational velocity of the drill string over time as the rotation velocity of the drill string is changed. Rotation of the drill string is started and the rotational velocity (or equivalently the frequency of rotation) is increased to R_1. The frequency is held at R_1 over time period [1]. When instructing a tool, this initial rotation frequency R_1 may be used to transfer data or information along the drill string, it may also be used to send a signal to prepare the drilling member for data transfer. This signal may transmit information to alert the drilling member that if subsequent rotation speeds follow a predetermined pattern then the intention is to transfer data to the drilling member. Also, this data set can be used to set a particular parameter which

is going to be transmitted along the drill string. It should be noted that the length of period [1] as well as the frequency of rotation is itself a variable parameter which can be used to send information. Using combinatorial data transmission wherein timing and frequency variables have pre-set limits reduces the possibility of operator errors and accidental actuations may be avoided.

After time period [1], the rotation of the drill string is either reduced to zero or is reduced below a threshold value for time period [2]. The threshold value is R_0. Time period [2] is primarily used to create a clear distinction between instructions.

The frequency of rotation of the drill string is then increased to R_2 for time period [3]. This variation in the rotation frequency represents an easily identifiable codification as it varies both in rotational frequency and duration from time period [1]. The duration of time period [3] is restricted once again by reducing the rotational frequency to below threshold value R_0 for a second time period [2].

After the second time period [2] the rotation frequency is increased to R_3 for time period [4]. Rotational frequency R_3 is lower than that of R_1 and R_2. Time period [4] can be used as a separate data set or it can be used as supplemental data set to that transmitted in time period [3]. It may also be used as a preamble to a following data set (in a similar manner to the data set of period [1]) or it may be used as a terminating data set which may return the parameters of the tool to an equilibrium position.

Figure 2A shows that the present invention may be used to transmit codification which is linear, progressive and discrete: each data set may be sequential and may be separated from a the last data set by a period of zero or low frequency data. Each data set is dependent on the speed of rotation of the drill string during a pre-determined time period for its numeric value.

There are thus two data variables in each data set i.e. frequency and duration, which may be controlled from the surface. To summarise, these two variables may be used in

a number if different ways in order to talk to the tool. The tool may have a number of different parameters which require instructions from the surface. The parameter which is to be changed may be set by the measured velocity or frequency of rotation and the amount which the parameter is to be changed by may be set by the duration of the signal. Alternatively, the parameter may be chosen by a preparatory data sequence (e.g. period [1] and the magnitude of the parameter may be communicated by the magnitude of the following velocity or frequency signal.

Averaging, standard code correction techniques, or other statistical means may be employed to improve the quality of the data obtained from each individual data set. Any number of data sets may be sequentially added in order to increase the quantity of data transmitted to the downhole instrumentation or mechanism(s).

Figure 2B shows a plot of rotation against speed similar to Figure 2A. Except in this Figure, the string is switched between a constant rotating speed V_{rot} and not rotating. In other words, there is only one variable which is duration as the rotational velocity which is related to the frequency is maintained constant. Figure 2B shows a simplification of the transmission method described with relation to figure 2A.

As in Figure 2A, four time periods are shown in Figure 2B, in period 1, the drill string rotates at V_{rot}, the logic means of the drilling member are configured to read rotation at V_{rot} as being an equilibrium stage where all logic parameters within the drill string are kept at their equilibrium values.

In period 2, the rotation of the drill string is stopped, the logic means of the drilling member vary a set parameter. For example, if the drilling direction of the drilling member is governed by the angular movement of a component of the drilling member (for example, 112 in Figure 4B), then the logic means may command the angular movement of the component for the whole of period 2.

When the drill string rotation is restarted, at the start of period 3, the movement of the component is stopped.

The movement of the component starts again at the start of period 4. (i.e. when the drill string rotation stops). Period 4 is twice as long as period 2. Therefore the component moves through twice the angle in period 4 as period 2.

Hence the duration of the period of non-rotation is converted into the angle of rotation for component 112.

Figure 3A shows a cross section of a down hole tool which may be used in accordance with an embodiment of the present invention. The actual tool shown in figure 3A is a modified version of the inventor's own prior art which is described in relation to figures 4A and 4B.

The tool comprises a outer housing 1 with an eccentric bore. An inner sleeve 2 is located within said bore such that the outer housing 1 is rotatably coupled about said inner sleeve 2. The inner sleeve 2 also has an eccentric bore which is configured to accommodate a rotating drill string member 3 such that said inner sleeve 2 can rotate relative to both said outer housing 1 and aid drill string member 3.

A magnet 4 is attached to said rotating member 3. The magnet is located in a pocket on said rotating member 3. This specific embodiment uses the magnet as an emitter. However, it will be appreciated by those skilled in the art that the magnet could be replaced by any type of emitting sensor.

The outer housing 1 contain instrument barrels 6. The instrument barrels 6 are provided with sensing means. During drilling of the well bore 7, the heavy portion of the outer housing seeks the low side of the well bore and the position of the outer housing remains relatively fixed with respect to the well bore. The drill string 3 and magnet 4 rotate relative to the outer housing. Lines of flux 5 radiate from the magnet 4

in such a manner as to overcome the Earth's ambient field. The flux lines 5 extend radially beyond the instrument barrel 6 such that sensors within the instrument barrel 6 can detect the intensity of the emitted magnetic field.

When the magnet 4 is rotated such that it is closest to the sensors in the instrument barrel 6, then a maximum in the magnetic field is detected. When the magnet 4 is furthest form the instrument barrel 6, then a minimum in the magnetic field is detected. The filed detected by the sensors may be sinusoidal if is possible to sense the radiated magnetic field at all times when the member 3 is rotating. However, as it is only necessary to measure the frequency of rotation of the member, it is adequate if the sensor is just configured to detect a maxima in the field when the magnet is at its closest to the sensor. In other words, the sensor just needs to detect a series of pulses where each pulse is equivalent to one each rotation of the member 3.

Thresholds may also be set which negate the effect of the Earth's magnetic field and which serve as limit switches. These limit switches may be employed as a means of logic control within the sensor array or within a logic control sub assembly.

A second instrument barrel 6a is also shown. This may also contain magnetic sensors. The provisions of two magnetic sensors allows the direction of the rotation of the drill string to be accurately determined as well as its magnitude.

The sensor which isolated within the instrument barrel is preferably situated in a stainless steel, or another magnetically transparent pressure vessel such that the instrumentation is isolated from the borehole pressure. The instrumentation barrel may comprises a magnetometer, or Hall effect device or the like for detecting the magnetic field.

Inevitably, there will be material between the magnetic sensor in the instrument barrel 6 and the magnet 4 located on the rotating member. This intervening material should, as far as possible, be magnetically transparent. In other words, the magnetic field should

pass through this material without becoming deflected or distorted. Materials which exhibit these properties include austenic stainless steels and other non-ferrous material.

Figure 3B shows a variation on the device of figure 3A, In figure 3B the rotating drill string is provided with four magnets 4 arranged at 90° to one another. In the figure the magnets 4 are embedded within the outer rotating wall of the member 3. However, it should be noted that the magnets could be embedded in the inner rotating wall of the member 3.

More sophisticated coding is achievable with more than one emitter. Further, the inversion of one of the sensors can be used to provide error checking or other programming advantages to the present invention. Multiple magnets may also be used to increase the frequency of the signal from the rotating member 3 or for actuation of multiple sensors within a single data set time frame, for example, as a means of compressing data.

Multiple magnets may have the same polarity or they may have alternating alignment of polarity. In figure 3B, the magnets 4 are arranged across the same section of the tubular. However, it will be appreciated that the magnets could be arranged at various axial spacings along the member 3.

Although not shown in either of figures 3A or 3B, the downhole device will have analysis means to analyse the information sent along the drill string. If the information which is sent along the drill string requires mechanical movement of a component of the drilling tool or member, then drive means are required to move the required component are instructed. For example, the drive means may move a component either radially or axially in the drilling tool. In addition to mechanical information, the drilling tool may also require instructions which are essentially electronic in nature. For example, information relating to the preferred rate of data transmission may be sent along the drill string.

In both the generalised and preferred embodiments of the assembly, it should be understood the different signalling means may be employed, that different configurations my be used and that other modifications may be made without departing from the spirit and scope of the present invention as defined by the appended claims.

CLAIMS:

1. An apparatus for the use of drilling or producing from a well bore, the apparatus comprising a downhole member capable of being attached to a tubular, means for rotating the tubular, control means for controlling the rotation of said tubular in order to transmit information along said tubular and means for monitoring the rotation of said tubular and for decoding said information transmitted along said tubular such that a magnitude of a parameter can be determined from the rotation of said tubular.

2. An apparatus according to claim 1, wherein the control means is configured to control the rotational velocity of the tubular.

3. An apparatus according to either of claims 1 or 2, wherein the control means is configured to stop the rotation of the tubular for a predetermined time.

4. An apparatus according to claim 3, wherein the monitoring means is configured to measure the time of non-rotation of the tubular.

5. An apparatus according to either of claims 3 or 4, wherein the monitoring means is configured to measure the time over which the tubular is continuously rotating.

6. An apparatus according to claim 5, wherein the monitoring means is configured to measure the time over which the tubular is continuously rotating at a particular rotational speed.

7. An apparatus according to any preceding claim, wherein the monitoring means is configured to count the number of rotations of the tubular.

8. An apparatus according to any preceding claim, wherein the monitoring means comprises a magnet.

9. An apparatus according to any preceding claim, wherein the monitoring means comprises at least one of a radioactive or sonic source.

10. An apparatus according to any preceding claim, wherein the monitoring means comprises a gravitational accelerometer configured to detected alternating variations in the gravitational field due to rotation of the tubular.

11. An apparatus according to any preceding claim, wherein said drilling member comprises:

a hollow rotatable mandrel having a concentric longitudinal bore;

an inner sleeve rotatably coupled about said mandrel, said inner sleeve having an eccentric longitudinal bore of sufficient diameter to allow free relative motion between said mandrel and said inner sleeve;

an outer housing having an outer surface, said outer housing is rotatably coupled around said inner eccentric sleeve, said outer housing having an eccentric longitudinal bore forming a weighted side adapted to automatically seek the low side of the wellbore and having sufficient diameter to allow free relative motion between said inner sleeve and

a plurality of stabilizer shoes longitudinally attached to or formed integrally with said outer surface of said outer housing;

drive means for selectively rotating said inner eccentric sleeve with respect to said outer housing and

logic means for controlling said drive means based on the information transmitted along said drill string.

12. An apparatus for transmitting information in a timely manner from the face of the Earth to a downhole assembly, whereby the rotation of the drill string is used as an output device, conveying information to components which are located in the wellbore, the apparatus comprising:

a device which is closely coupled to either the drill string , or a non-rotating sub assembly, which emits a signal or influences its environment such that the rotation of the drillstring is used to activate a sensor means which may be integrated into either the

drill string, or a non-rotating sub-assembly with a timing device such that the sensor outputs derived from the rotation of the drillstring system may be measured against a time-based system such that meaningful encoding may be accomplished, which may be coupled to an actuation or switching mechanism or mechanisms.

13. An apparatus according to claim 12, wherein the emitter or device influencing the environment comprises a magnet or a magnetic device.

14. An apparatus according to claim 12, wherein the emitter or device influencing the environment comprises a mechanical switch which is activated by the rotation of the drill string.

15. An apparatus according to claim 12, wherein the emitter or device influencing the environment comprises at least one of a sonic or radioactive source.

16. A method of transmitting information along a tubular to a downhole member located within a well bore, the method comprising the steps of:

rotatably driving said tubular, wherein the rotation of said tubular is controlled accordance with information which is to be transmitted along said tubular;

monitoring the rotation of said tubular; and

analysing the monitored rotation of said tubular such that a magnitude of a parameter can be determined from the rotation of said tubular.

17. A method according to claim 16, wherein the step of monitoring the rotation of said tubular comprises the step of monitoring the rotational velocity of the tubular.

18. A method according to either of claims 16 or 17, wherein the step of monitoring the rotation of the tubular comprises the step of timing a period of non-rotation of the tubular.

19. A method according to claim 16, wherein the step of driving the tubular comprises the step stopping the rotation of the tubular for a pre-determined time determined by the information which is to be transmitted along the tubular.

20. A method according to claim 16, wherein the step of monitoring the rotation of the tubular comprises the step of measuring the time over which the tubular is continuously rotating at a particular frequency.

21. An apparatus as substantially hereinbefore described with reference to any of figures A, 1A to 3B.

22. A method as substantially hereinbefore described with reference to any of figures A, 1A to 3B.

The Patent
PATENTS • DESIGNS

CHARTER MARK

INVESTOR IN PEOPLE

Application No: GB 9926545.6
Claims searched: 1-22

Examiner: Joseph Mitchell
Date of search: 12 February 2001

Patents Act 1977
Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.S): E1F (FCB, FCU, FHK)

Int Cl (Ed.7): E21B

Other: EPODOC, WPI, JAPIO

Documents considered to be relevant:

Category	Identity of document and relevant passage		Relevant to claims
X&Y E	GB 2352743 A	SCHLUMBERGER HOLDINGS LTD. (Whole doc but especially Pg4 lines 20-32 & 35-37, Pg5 lines 1-33, Pg7 lines 32-33)	X:1-10,12-13,15-20 Y:11
Y	WO 9631679	McLOUGHLIN ET AL (Pg6 line 1-Pg8 line 19)	11
X&Y	US 4763258	PAUL D. ENGELDER(Whole document)	X:1-10,12-13,15-20 Y:11
X&Y	US 3908453	JOHN D. JETER(whole document but especially Col 3 lines 12-35)	X:1-10,12-20 Y:11

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.